BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

FILED

2008 JUN 12 P 4:09

PUBLIC UTILITIES COMMISSION

In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate the Implementation of Feed-in Tariffs	DOCKET NO. 2008-0273

JOINT RESPONSES TO LEGAL QUESTIONS REGARDING FEED-IN TARIFFS OF THE HECO COMPANIES AND CONSUMER ADVOCATE

AND

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Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), Maui Electric Company, Limited ("MECO"),[1] and the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs ("Consumer Advocate") respectfully submit their Joint Responses to Legal Questions Regarding Feed-In Tariffs ("Responses").

BACKGROUND REGARDING PURPA AND HAWAII'S RPS LAW

The following section of these Responses provides background information regarding the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"), and Hawaii's renewable portfolio standards ("RPS") law, set forth in Part V, Chapter 269 of the Hawaii Revised Statutes ("HRS"), insofar as these federal and state provisions relate to feed-in tariffs ("FIT" or "FiT").

A. PURPA

1. PURPA Qualifying Facilities

The Commission's rules relating to Qualifying Facilities ("QFs") and power purchase agreements ("PPA") between QFs and electric utilities are codified in its Standards for Small

[1] HECO, HELCO and MECO are collectively referred to herein as the "HECO Companies".

Power Production and Cogeneration, and are included in Title 6, Chapter 74, of the Hawaii Administrative Rules ("HAR"). The rules were adopted in 1982 (and amended from time to time thereafter) pursuant to rules adopted by the Federal Energy Regulatory Commission ("FERC") pursuant to PURPA.

In general, a QF is a cogeneration facility or a small power production facility that is a qualifying facility under HAR § 6-74-4 and subpart 2 of the regulations of the FERC regarding qualifying cogeneration and small power production facilities, 18 C.F.R. Part 292. HAR § 6-74-1.

The rules provide that a small power production facility is a qualifying facility if it meets the: (1) Maximum size criteria specified in §6-74-5(a) (generally, 80 MW or less); (2) Fuel use criteria specified in § 6-74-5(b) (i.e., the primary energy source of the facility shall be biomass, waste, renewable resources, solar, wind, geothermal, or any combination thereof, and more than 75% of the total energy input shall be from these sources); and (3) Ownership criteria specified in § 6-74-7. A cogeneration facility is a QF if it meets: (1) Any applicable operating and efficiency standards specified in § 6-74-6; and (2) The ownership criteria specified in § 6-73-7. The ownership criteria required that not more than 50% of the equity interest in the facility be held by electric utilities or their affiliates. However, this ownership criteria has been rescinded as a result of the Energy Policy Act of 2005, and the operating and efficiency standards for qualifying cogeneration standards have been modified. As a result, the Commission's rules will have to conform to FERC's new rules.

PURPA FERC Amended Rules

On August 8, 2005, the Energy Policy Act of 2005 ("EPAct 2005") was signed into law. Energy Policy Act of 2005, Pub. L. 109-58, 119 Stat. 594 (2005). Section 210(n) of PURPA, as

added by § 1253 of EPAct 2005, required FERC to issue a rule revising the criteria for new cogeneration facilities to ensure that those facilities meet the requirements of Section 210(n)(1)(A) of PURPA, including that the thermal output of a new qualifying cogeneration facility be used in a "productive and beneficial manner."

Under the amended FERC rules, issued February 2, 2006, and effective March 17, 2006, any new cogeneration facility must show that (1) the thermal energy output of the cogeneration facility is used in a productive and beneficial manner; and (2) the electrical, thermal, chemical and mechanical output of the cogeneration facility is used fundamentally for industrial, commercial, residential or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as state laws applicable to sales of electric energy from a QF to its host facility. The electrical, thermal, chemical and mechanical output of the cogeneration facility will be considered used fundamentally for industrial, commercial, or institutional purposes and not intended fundamentally for sale to an electric utility if at least 50% of the aggregate of such output, on an annual basis, is used for industrial, commercial, residential or institutional purposes. In addition, applicants for facilities that do not meet this safe harbor standard may present evidence to the Commission that the facilities should nevertheless be certified given state laws applicable to sales of electric energy or unique technological, efficiency, economic, and variable thermal energy requirements. In applying the new regulation, FERC applied a rebuttable presumption that new cogeneration facilities that are 5 MW or smaller satisfy the requirement that the thermal energy output of the new cogeneration facility is used in a productive and beneficial manner.

Section 1253(b) of EPAct 2005 amended §§ 3(17)(C) and 3(18)(B) of the Federal Power Act ("FPA") by eliminating the ownership limitations for QFs previously contained in those sections. Section 292.206 of FERC's regulations was designed to implement the prior statutory requirement that a qualifying cogeneration or small power production facility must be owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities). FERC implemented §1 253(b) of EPAct 2005 by eliminating § 292.206 from its regulations, and thus eliminating the ownership limitations for all QFs – both existing and new. FERC also deleted §§ 292.203(a)(3) and 292.203(b)(2) from its regulations describing the general requirements for qualifying status.

State Latitude

FERC has stated that state regulatory authorities are to be afforded "great latitude" in determining the manner of implementation of PURPA, and that FERC would provide "an opportunity for experimentation" in this implementation. Cogeneration, 61 F.E.R.C. ¶61,252, 1992 FERC LEXIS 2513, *11.

2. Electric Utility Obligations Under PURPA

An electric utility's obligations under the QF rules are specified in HAR § 6-74- 21:

> (a) Subject to the qualifications set forth in this chapter, each electric utility shall purchase, in accordance with §§6-74-22 to 6-74-24, any energy and capacity which is made available from a qualifying facility:
>
> (1) Directly to the electric utility; or
>
> (2) Indirectly to the electric utility in accordance with subsection (d).
>
> (b) Each electric utility shall sell to any qualifying facility, in accordance with §6-74-25, any energy and capacity requested by the qualifying facility.

> (c) Any electric utility shall make any interconnection with any qualifying facility as may be necessary to accomplish purchases or sales under this subchapter. The obligation to pay for any interconnection costs shall be determined in accordance with §6-74-26. . . .
>
> . . .
>
> (e) Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any applicable standards established in accordance with [section] §6-74-28.

Thus, in general, as a result of PURPA, an electric utility is obligated to offer to purchase energy and capacity from QFs at rates that do not exceed avoided costs[2] under reasonable terms and conditions, and to offer to interconnect with such QFs at their costs. However, an electric utility's obligation to purchase energy and capacity is not absolute. There are circumstances where a utility is not obligated to purchase energy and/or capacity made available from a QF.

One example of this is the situation where a QF seeks to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a situation, the utility is only obligated to pay for energy or capacity that the utility can use to meet its total system load. The FERC Preamble on electric utility obligations under 18 C.F.R. § 292.303, Order No. 69, 45 Fed. Reg. 12214, 12219 (1980) ("FERC Commentary") provides in relevant part:

> A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load. These rules imply no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale.[3]

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[2] As defined in the Commission's avoided cost rules, "avoided costs" means the "incremental or additional costs to an electric utility of electric energy or firm capacity or both which costs the utility would avoid by purchase from the qualifying facility." HAR § 6-74-1.

[3] Id. With respect to the FERC Commentary, the California Public Utilities Commission has noted:

There is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements. It is well-established that "while utilities may have an obligation under PURPA to purchase from a QF, that obligation does not require a utility to pay for capacity that it does not need."[4] Moreover, there is no obligation under PURPA for a utility to enter contracts to make purchases which would result in rates which are not "just and reasonable to electric consumers of the electric utility and in the public interest" or which exceed "the incremental cost to the electric utility of alternative electric energy." 16 U.S.C. § 824a-3(b) (1994).[5]

In addition, an electric utility is not obligated to purchase energy or capacity from a QF where purchasing energy or capacity from a generating facility would conflict with a utility's obligation to provide reliable and adequate electric service. From the perspective of the utility and the utility's customers, it does not make any sense to require a utility to purchase energy or capacity from a QF when such purchases could jeopardize a utility's system performance and reliability.

> FERC has therefore recognized that we must balance the PURPA mandate that utilities purchase energy and capacity from QFs with the overarching requirement that electric utilities may only charge just and reasonable rates for the power they supply to their customers.

Cal. Pub. Util. Comm'n Decision 07-09-040; Rulemaking 04-04-003; Rulemaking 04-04-025, filed April 22, 2004 at 198.

The Washington Utilities and Transportation Commission has similarly interpreted the FERC Commentary to mean –

> that the value of additional capacity may well be zero if the utility already has surplus capacity.
>
> * * *
>
> If the WUTC required the company to purchase capacity which it does not need, the logic of promoting efficient use of energy would be violated.

Re Washington Util. and Transp. Comm'n v. The Washington Water Power Co., Cause No. U-83-14, 1983 Wash. UTC LEXIS *11, *24 (November 9, 1983).

[4] Re City of Ketchikan, Nos. EL01-26-000, EL01-32-000, 94. F.E.R.C. 61,293, 62,062, 2001 FERC LEXIS 529, 18-19 (2001). Thus, firm capacity payments are only required when capacity costs are avoided.

[5] Id., 2001 FERC LEXIS 529 at 15 (footnotes omitted).

3. Contract Terms

As a practical matter, a utility's "PURPA" obligation is to offer to purchase at avoided costs under reasonable terms and conditions. At the same time, neither PURPA nor the Commission's PURPA rules specify all the terms and conditions that must be offered to QFs. If a utility offers more favorable terms through another process, such as a feed-in tariff ("FIT"), then QFs will need to comply with the FIT provisions in order to receive those more favorable terms, because neither PURPA nor the Commission's rules require that a utility offer those terms.

With the exception of price, interconnection and curtailment, the rules do not specify the terms and conditions upon which the purchase of capacity and/or energy must be made by the electric utility. For example, a utility is not required by PURPA to offer (1) a specific contact term, (2) a minimum take contract, (3) payments on any other basis than energy delivered, or (4) curtailment priority over existing energy producers.

4. Avoided Costs

As a result of PURPA, QFs are allowed to submit offers to sell firm capacity and/or energy to the utility at prices at or below avoided costs, pursuant to the rules established by FERC under PURPA, and state rules implemented pursuant to the FERC rules.

As defined in the Commission's avoided cost rules, "avoided costs" means the "incremental or additional costs to an electric utility of electric energy or firm capacity or both which costs the utility would avoid by purchase from the qualifying facility." HAR § 6-74-1.

HAR § 6-74-23 specifies factors affecting rates for purchases, and HAR § 6-74-24 addresses periods during which purchases are not required. HAR § 6-74-22(a) specifies that

rates for purchases shall:

> (1) Be just and reasonable to the electric consumer of the electric utility and in the public interest;
>
> (2) Not discriminate against qualifying cogeneration and small power production facilities; and
>
> (3) Be not less than one hundred per cent of avoided cost for energy and capacity purchases to be determined as provided in §6-74-23 from qualifying facilities and not less than the minimum purchase rate.

The requirement that rates for purchase be not less than 100% of avoided cost and not less than the minimum purchase rate was based on HRS § 269-27.2(c), as amended in 1983 by Act 243, 1983 Haw. Sess. L. 516-17, which allowed the Commission to prescribe the rate to be paid to a nonfossil fuel producer, and directed the Commission, in determining the just and reasonable rate to be paid to such a producer, to consider, on a generic basis, the minimum floor a utility should pay. As noted below, in 2004, the Legislature repealed that portion of Section 269-27.2(c) that required the inclusion of minimum floor rates. Act 95, §3, 2004 Haw. Sess. L. 385.

Similar to the FERC rules, the Commission rules specify that each QF shall have the option either:

> (1) To provide energy as the qualifying facility determines that energy to be available for those purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided energy costs calculated at the time of delivery, determined after consideration of the factors set forth in §6-74-23; or
>
> (2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for those purchases, at the option of the qualifying facility exercised prior to the beginning of the specified term, shall be based on either:
>
> > (A) The avoided costs calculated at the time of delivery, determined after consideration of the factors set forth in § §6-74-5(b)6-74-23; or

(B) The avoided costs calculated at the time the obligation is incurred, determined after consideration of the factors set forth in §6-74-23.

HAR § 6-74-22(c).

Avoided costs can be determined by (1) the utility, on a case-by-case basis, using a differential revenue requirements ("DRR") method,[6] a proxy method,[7] a peaker method,[8] or other method acceptable to the Commission, (2) the regulatory commission, on an administrative basis, or (3) by a competitive bid process.[9] If the utility is determining avoided costs for a resource that the utility would install itself or acquire itself through a competitive bid process but for the power purchase arrangement, then the avoided cost generally becomes equivalent to the cost of the resource.

FERC has held that jurisdiction over the rates charged by QFs for sales at wholesale (which includes sales to public utilities) is vested in FERC, and that PURPA preempts state statutes or regulations that would require the payment of a rate in excess of avoided cost (determined in accordance with the FERC rules, as implemented by the States) to QFs.[10] See Re

[6] In the DRR method, the utility's revenue requirements for its resource plan without the independent power producer ("IPP") are compared to the utility's revenue requirements for its resource plan with the IPP allowed to defer or replace utility-owned new generation and/or displace utility system generated electricity.

[7] The proxy plant method identifies the next unit that would be added by the utility. Both avoided capacity and energy costs are set based upon the cost of the proxy unit.

[8] The peaker method is a marginal cost approach. It is referred to by several names including the component method and short-run marginal cost. In applying the method, avoided capacity costs are set equal to the cost of a new peaking unit (or lower if there is surplus capacity) and avoided energy costs are determined as system marginal energy costs.

[9] FERC has held that regardless of whether a State regulatory authority determines avoided cost for a QF administratively, through competitive bidding, or some combination thereof, it must in its process reflect prices available from all sources able to sell to the utility whose avoided cost is being determined. Re Southern California Edison Co., Docket No. EL95-1 6-000, Order on Petition for Enforcement Action Pursuant to Section 210(h) of PURPA (F.E.R.C. Feb. 23, 1995), reconsideration denied, Order on Requests for Reconsideration (June 2, 1995).

[10] FERC also held that its decision would not have retroactive effect, and that FERC would not entertain requests to invalidate pre-existing contracts where the avoided cost issue could have been raised, but was not. According to the FERC ruling, state commissions could require payment rates in excess of avoided costs for entities that are not QFs or public utilities (under the Federal Power Act).

Connecticut Light & Power Co., Docket No. EL93-55-000, Order Granting Petition for Declaratory Order (FERC Jan. 11, 1995).

FERC's avoided cost cap rulings appear to preclude the payment of an "externalities" adder to a renewable energy producer.[11] FERC has indicated that, "in setting avoided cost rates, a state may only account for costs which actually would be incurred by utilities," and that a state "may not set avoided costs rates . . . by imposing environmental adders or subtractors that are not based on real costs that would be incurred by utilities." Re Southern California Edison Co., Docket No. EL95-1 6-000, Order on Requests for Reconsideration (F.E.R.C. June 2, 1995).[12]

5. Set Asides

The FERC rulings should not preclude the consideration of externalities in the selection of a utility resource plan (which could include renewable resources, or which could form the basis for a higher utility avoided cost determination for purchased power resources, including renewable resources, that provide equivalent externalities benefits). The qualitative consideration of externalities can have an impact in increasing the avoided cost available to renewable resources. For example, HECO did not adopt the least utility-cost plan as its preferred

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[11] The PUC adopted its Framework for Integrated Resource Planning (the "IRP Framework") by Decision and Order No. 11523 (March 12, 1992), as modified by Decision and Order No. 11630 (May 22, 1992). The IRP Framework requires that external costs and benefits be considered in the integrated resource planning process, but does not specify the weight to be given externalities in selecting the utility's preferred integrated resource plan ("IRP Plan"). Re Integrated Resource Planning, Docket No. 7257, Decision and Order No. 13839 (March 31, 1995) at 25.

External costs are direct or indirect costs to or negative impacts on the activities of entities outside the utility. Under the IRP Framework, external costs include "environmental, cultural and general economic costs." In general, societal costs are equal to utility costs plus external costs (less "transfer" payments, which are payments from the utility, such as taxes, to society in general). IRP Framework, ¶I.

[12] States may choose to provide taxpayer subsidies for renewable energy, not utility avoided cost adders. Rates for QF power that exceeds avoided cost do not violate PURPA if they are offset by a "dollar-for-dollar tax credit, calculated and credited to the utility on a month-by-month basis, that equals the amount by which rates . . . exceeded the utility's avoided cost." Re CGE Fulton. L.L.C, Docket No, EL95-27-001, 70 F.E.R.C. 161,290, 1995 FERC Lexis 404 (F.E.R.C. March 15, 1995), reconsideration denied, 71 F.E.R.C. 61,232, 1995 FERC Lexis 1027 (May 25, 1995).

Integrated Resource Planning ("IRP") Plan in Docket No. 7257. HECO adopted a somewhat more expensive plan, from a utility-cost standpoint, that included coal-fired generation in order to reduce HECO's dependency on fuel oil. To the extent that a renewable resource can provide equivalent benefits, the renewable resource could receive a price higher than that based on the utilities least utility-cost plan (which might include only oil-fired generation).

Thus, it appears that the utility can establish "set asides" for resources that will allow the utility to obtain the designated attributes, as long as the set asides do not arbitrarily exclude other resources that would provide the same attributes.

Moreover, it now is less likely that fossil-fuel fired qualifying cogeneration facilities will be competing with qualifying small power production facilities that offer externality benefits. This is one of the potential benefits of EPAct 2005, even though it does not exclude Hawaii's obligation to continue to comply with PURPA. As explained above, FERC has redefined the QF requirements for what used to be known as "PURPA machines" (i.e., entities that found another use for processed steam that was not really an economic process, but a process intended to qualify them as a QF).

B. HRS § 269-27.2

HRS § 269-27.2 now provides that:

> (a) The public utilities commission shall investigate and determine the extent to which electricity generated from nonfossil fuel sources is available to public utilities that supply electricity to the public, which electricity is in excess of that utilized or otherwise needed by the producers for their internal uses and which the producers are willing to make available to the electric public utilities.
>
> (b) The public utilities commission may direct public utilities that supply electricity to the public to arrange for the acquisition of and to acquire electricity generated from nonfossil fuel sources as is available from and the producers are willing and able to make available to the public utilities, and to employ and dispatch the nonfossil fuel generated electricity in a manner consistent with the availability thereof to maximize the reduction in consumption of fossil fuels in the generation of

electricity to be provided to the public. To assist the energy resources coordinator in effectuating the purposes of chapter 201N, the public utilities commission may develop reasonable guidelines and timetables for the creation and implementation of power purchase agreements.

(c) The rate payable by the public utility to the producer for the nonfossil fuel generated electricity supplied to the public utility shall be as agreed between the public utility and the supplier and as approved by the public utilities commission; provided that in the event the public utility and the supplier fail to reach an agreement for a rate, the rate shall be as prescribed by the public utilities commission according to the powers and procedures provided in this chapter.

The commission's determination of the just and reasonable rate shall be accomplished by establishing a methodology that removes or significantly reduces any linkage between the price of fossil fuels and the rate for the nonfossil fuel generated electricity to potentially enable utility customers to share in the benefits of fuel cost savings resulting from the use of nonfossil fuel generated electricity. As the commission deems appropriate, the just and reasonable rate for nonfossil fuel generated electricity supplied to the public utility by the producer may include mechanisms for reasonable and appropriate incremental adjustments, such as adjustments linked to consumer price indices for inflation or other acceptable adjustment mechanisms.

(d) Upon application of a public utility that supplies electricity to the public, and notification of its customers, the commission, after an evidentiary hearing, may allow payments made by the public utility to nonfossil fuel producers for firm capacity and related revenue taxes to be recovered by the public utility through an interim increase in rates until the effective date of the rate change approved by the commission's final decision in the public utility's next general rate proceeding under section 269-16, notwithstanding any requirements to the contrary of any other provision in this chapter or in the commission's rules or practices; provided the amount recovered by the utility and the amount of increase in rates due to the payments for firm capacity and related revenue taxes to be charged to the consumers of the electricity are found by the commission to be:

(1) Just and reasonable;

(2) Not unduly prejudicial to the customers of the public utility;

(3) Promotional of Hawaii's long-term objective of energy self-sufficiency;

(4) Encouraging to the maintenance or development of nonfossil fueled sources of electrical energy; and

(5) In the overall best interest of the general public.

The evidentiary hearing provided for in this subsection shall be conducted expeditiously and shall be limited to evidence related to the above findings. Notwithstanding section 269-16, no public hearing shall be required, except as the commission in its discretion may require.

HRS § 269-27.2 was enacted in1977 (Act 102, § 3), prior to the enactment of PURPA in 1978, and significant amendments were made in 1982 (Act 266, §2), 1983 (Act 266, § 2), 1988 (Act 246, § 2), 2004 (Act 95, § 3), 2006 (Act 162, § 3), 2008 (Act 207, § 4) and 2009 (Act 50, § 2).

As originally enacted, § 269-27.2 provided that:

(a) The public utilities commission shall investigate and determine the extent to which electricity generated from non-fossil fuel sources is available to public utilities which supply electricity to the public, which electricity is in excess of that utilized or otherwise needed by the producers for their internal uses and which such producers are willing to make available to such public utilities.

(b) The public utilities commission may direct public utilities which supply electricity to the public to arrange for the acquisition of and to acquire such electricity generated from non-fossil fuel sources as is available from and which the producers of same are willing and able to make available to such public utilities, and to employ and dispatch such non-fossil fuel generated electricity in a manner consistent with the availability thereof to maximize the reduction in consumption of fossil fuels in the generation of electricity to be provided to the public.

(c) The rate payable by the public utility to the producer for such non-fossil fuel generated electricity supplied to the public utility shall be as agreed between the public utility and the supplier and as approved by the public utilities commission; provided, however, that in the event the public utility and the supplier fail to reach an agreement for such rate, such rate shall be as prescribed by the public utilities commission according to the powers and procedures provided in this chapter.

(1) In the exercise of its authority to determine the just and reasonable rate for the non-fossil fuel generated electricity supplied to the public utility by the producer, the commission shall give due consideration, among other factors, to the costs that the public utility would incur in the supply of electricity, to the need in the public interest of adequate and economical electric service by the public utility, and to the need of revenues sufficient to enable the producer of non-fossil fuel generated electricity to provide the electricity to the public utility.

The provision was based on the following findings in Act 102, § 1:

> The legislature finds that electricity generated from the combustion of bagasse presently constitutes a substantial source of power in the State of Hawaii; that the combustion of non-fossil materials including bagasse, wood materials and combustible solid waste materials constitute a significant potential source of additional power available for public use; and that encouraging utilization of non-fossil fuel sources of energy offers advantages to the State that would:
>
> (a) Promote an important reduction of State dependence upon imported petroleum products and other rapidly depleting fossil fuel sources, which consequently would reduce the State's vulnerability to economic dislocation and public inconvenience resulting from sudden or long-term unavailability of fossil fuels by reason of adverse action by foreign oil suppliers, shipping industry strikes, or exhaustion of fossil fuel supplies;
>
> (b) Improve the State balance of payments posture by reducing purchases of fuel from extra-State sources and circulated into the State economy the funds expended for power generated from State fuel sources that otherwise would have entered other economies;
>
> (c) Create jobs in the State by encouraging development of non-fossil fuel power production industry;
>
> (d) Encourage utilization of alternative renewable fuel sources such as bagasse, wood materials and combustible solid waste materials, which currently are not being employed to their full potential;
>
> (e) Promote expanded use of technology which presently exists and is being utilized currently by the State sugar industry in the generation of power from combustion of bagasse and which therefore does not require the research for development of technology or public financial assistance necessary for other non-fossil fuel energy alternatives such as solar, wind, geothermal and nuclear power, and which does not pose the degree of health, safety or environmental risks concomitant with nuclear power and transportation of fuel oil;
>
> (f) Contribute to the viability of the State sugar industry by encouraging the sale and utilization of excess power generated from combustion of bagasse; and
>
> (g) Would not require installation of costly equipment or individual appliances by users as would be required for the utilization of solar energy.

In 1982 and 1983, § 269-27.2 was amended to require that rates for purchase be not less than 100% of avoided cost and directed the Commission, in determining the just and reasonable

rate to be paid to a non-fossil fuel producer, to consider, on a generic basis, the minimum floor a utility should pay.[13] Act 266, § 2, 1982 Haw. Sess. L. 693-94; Act 243, § 1, 1983 Haw. Sess. L. 516-17.

With respect to adding the "not less than 100% of avoided cost" standard, Act 266 (1982) states that: "The legislature finds that maximization of the use of locally available nonfossil fuels is in the best interest of the State, but that such maximization will not be achieved until the value of such fuels to the public is recognized to be at least equal to the cost of fossil fuels to be displaced. Accordingly, such use should be encouraged to the greatest practicable extent." Act 266, Section 1 of the 1982 Session Laws of Hawaii.

The inclusion of minimum rates in PPAs, however, sometimes resulted in payment rates in excess of avoided costs and, arguably, the requirement was preempted, with respect to QFs, by FERC's avoided cost cap rulings (i.e., that PURPA preempts state statutes or regulations that would require the payment of a rate in excess of avoided cost to QFs). As noted below, this requirement was rescinded in 2004.

In 1988, § 269-27.2 was amended to add subpart (d), which allows a utility to begin recovering firm capacity payments made to non-fossil fuel producers between rate cases. Subpart (d) recognizes the importance of keeping the utilities whole, while encouraging renewable energy development. It provides that the Commission "may allow payments made by the public utility to nonfossil fuel producers for firm capacity and related revenue taxes to be recovered by the public utility through an interim increase in rates until the effective date of the

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[13] Act 243, § 1 provides in part:

> In determining the amount of the payment in relation to avoided cost, as that cost shall later be defined by the Commission, the Commission shall consider, on a generic basis the minimum floor a utility should pay, giving consideration not only to the near-term adverse consequences to the ultimate consumers of utility provided electricity, but also to the long term desirable goal of encouraging to the greatest extent practicable, the development of alternative sources of energy.

rate change approved by the commission's final decision in the public utility's next general rate proceeding . . . ." The Hawaii Senate's Committees on Agriculture, Energy and Ocean Resources, and on Public Utilities found that, "The recovery of payments made to nonfossil fuel producers by an electric public utility will encourage the public utility to utilize the nonfossil fuel sources." See Act 246, Relating to Alternative Energy § 1, S.B. No. 2362 (1988). Agreeing with this position, the Legislature's subsequent conference committee report stated in part: "This interim rate relief would properly compensate the electric utility in a timely manner and thereby encourage their use of nonfossil fuel generated electricity." See Conf. Com. Rep. HC 32-88, in the 1988 House Journal at 772.

In 2004, the Legislature repealed that portion of Section 269-27.2(c) that required the inclusion of minimum floor rates. Act 95, §3, 2004 Haw. Sess. L. 385. As amended in 2004, § 269-27.2(c) provided that:

> In the exercise of its authority to determine the just and reasonable rate for the nonfossil fuel generated electricity supplied to the public utility by the producer, the commission shall establish that the rate for purchase of electricity by a public utility shall not be more than one hundred per cent of the cost avoided by the utility when the utility purchases the electrical energy rather than producing the electrical energy. (Emphasis added.)

This was consistent with the definition of "cost effective" added to the RPS law by the same Act.

Subsection (c) was again amended in 2006 by Act 162 (23rd Haw. Leg.), which added the following:

> The commission's determination of the just and reasonable rate shall be accomplished by establishing a methodology that removes or significantly reduces any linkage between the price of fossil fuels and the rate for the nonfossil fuel generated electricity to potentially enable utility customers to share in the benefits of fuel cost savings resulting from the use of nonfossil fuel generated electricity. As the commission deems appropriate, the just and reasonable rate for nonfossil fuel generated electricity supplied to the public utility by the producer may include mechanisms for reasonable and appropriate incremental adjustments, such as adjustments linked to consumer price indices for inflation or other acceptable adjustment mechanisms.

The language was intended to reflect the success of MECO in negotiating a Power Purchase Contract for As-Available Energy dated December 3, 2004, with Kaheawa Wind Power, LLC ("KWP") (the "KWP PPC"), in which 70% of the energy payments that MECO makes to KWP are based on a fixed payment rate.[14] To comply with PURPA in the case of QFs[15], the "fixed" rates set pursuant to the third paragraph of § 269-27.2(c) can take into account the energy costs avoided by the utility in purchasing the energy from the non-fossil fuel producer. As was the case with the KWP PPA, this can be done by determining or otherwise taking into consideration the utility's avoided energy costs, which primarily consist of avoided oil costs, and then levelizing the resulting avoided energy costs on a discounted present value basis over the relevant payment period.[16]

The resulting avoided energy cost can be compared to and limited by a "proxy" avoided energy cost based on the utility's cost to construct and own a renewable energy facility. This would take into account the utility's to avoid fossil-fuel based energy costs by constructing and operating its own renewable energy facilities, and would allow utility customers "to share in the benefits of fuel cost savings resulting from the use of nonfossil fuel generated electricity" in accordance with HRS §269-27.2(c).

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[14] The remaining 30% is based on MECO's avoided energy cost data filed with the Commission pursuant to Hawaii Administrative Rules §6-74-17(b), as may be amended from time to time or as may be superseded by applicable laws, rules or Commission orders. The PPC has on-peak and off-peak energy prices, both of which are based on a combination of both a fixed and a variable pricing component. See Application filed December 16, 2004, in Docket No. 04-0365, for approval of the KWP PPC.

[15] With an as-available QF, the utility is obligated to offer to pay avoided energy cost at the time of delivery.

[16] The resulting avoided energy cost can be compared to and limited by a "proxy" avoided energy cost based on the utility's cost to construct and own a renewable energy facility. This would take into account the utility's to avoid fossil-fuel based energy costs by constructing and operating its own renewable energy facilities, and would allow utility customers "to share in the benefits of fuel cost savings resulting from the use of nonfossil fuel generated electricity" in accordance with HRS §269-27.2(c).

In 2009, HRS § 269-27.2 was amended to delete the following language that had been added in 2004: "In the exercise of its authority to determine the just and reasonable rate for the nonfossil fuel generated electricity supplied to the public utility by the producer, the commission shall establish that the rate for purchase of electricity by a public utility shall not be more than one hundred per cent of the cost avoided by the utility when the utility purchases the electrical energy rather than producing the electrical energy." Act 50 (26th Haw. Leg.), H.B. No. 1270, S.B.2, signed by the Governor on May 6, 2009 ("Act 50").

In addition, Act 50 amended the definition of "cost effective" in the RPS law (HRS § 269-91) by adding the underscored: "'Cost-effective' means the ability to produce or purchase electric energy or firm capacity, or both, from renewable energy resources at or below avoided costs or as the commission otherwise determines to be just and reasonable consistent with the methodology set by the public utilities commission in accordance with section 269-27.2."

In Section 1 of the act, the Legislature found that:

> [G]iven the alarming rise and precipitous drop of oil prices over the past year and a general lack of confidence in long-term fuel pricing forecasts, the regulatory standard of avoided cost has been difficult to define and has created barriers in the negotiations process for power purchase agreements, especially for clean energy products. Therefore, the purpose of this Act is to refocus the regulatory standard to a methodology that is just and reasonable by significantly reducing any linkages between the volatile prices of fossil fuels and the rate for nonfossil fuel generated electricity. This Act also potentially enables utility customers to share in the benefits of price stability and fuel cost savings resulting from the use of nonfossil fuel generated electricity.

Subsections (a) and (b), and the first paragraph of subsection (c) of HRS § 269-27.2, have remained virtually unchanged since the enactment of HRS § 269-27.2 in 1977.[17] What has

[17] Subsection (b) was amended by § 4 of Act 207 (2008), which established the position of an energy resources coordinator. Act 207 (H.B. No. 2862, H.D. 2, S.D. 2, C.D. 1) was enacted to establish a renewable energy facility siting process for state and county permits required for siting, development,

changed is the standard to be applied by the Commission in setting the rate payable by the public utility to the producer for the nonfossil fuel generated electricity in the event the public utility and the supplier fail to reach an agreement for a rate.

1. Definition of "Nonfossil Fuel Producer"

HRS §§ 269-1 and 269-27.2 refer to "nonfossil fuel producers" and to "producers" of "electricity generated from nonfossil fuel sources" (both of which are referred to herein as "nonfossil fuel producers"). However, the statutory provisions do not define "nonfossil fuel producers" and there has not been a determination by the Commission or a Hawaii court as to the maximum percentage of fossil fuel that a producer can use and still be considered a "nonfossil fuel producer."

A "nonfossil fuel producer", as the term is used in HRS § 269-27.2(d), is a producer of electricity generated primarily from nonfossil fuel sources. See HRS § 269-1(7). Neither the statute, nor the legislative history, provides further insight as to the maximum percentage of fossil fuel (i.e., 50%, or 25%, etc.) that a producer can use and still be considered a nonfossil fuel producer.[18]

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construction, and operation of a new renewable energy facility with a capacity of at least 200 MW. To assist the coordinator, the Act provides that the Public Utilities Commission "may develop reasonable guidelines and timetables for the creation and implementation of power purchase agreements."

[18] For example, HRS § 269-27.2, with its references to nonfossil fuel sources, was originally added to Hawaii law in 1977 by Act 102, prior to the enactment of PURPA. As noted above, one of the purposes of Act 102 was to promote expanded use of the existing technology utilized by the State's sugar industry in the generation of power from combustion of bagasse. That "technology" also involved the burning of fuel oil when bagasse was not available.

Section 269-27.2(d), which specifically uses the term "nonfossil fuel producer", was also added to Hawaii law in 1988 by Act 246 in order to encourage the production of electric energy from nonfossil fuel producers such as Hilo Coast Processing Company ("HCPC") (which burned a combination of bagasse and fuel oil).

In addition to adding the predecessor of what is now Section 269-27.2 to Hawaii law, Act 102 added an exclusion to the definition of public utility, which provides that the term public utility "shall not include any person who controls, operates or manages plans or facilities for production, transmission or furnishing of power primarily or entirely from nonfossil fuel sources for its internal uses but who also

C. RPS STATUTORY FRAMEWORK

1. Renewable Portfolio Standards

HRS § 269-92(a), as amended by Act 162 (2006), provides that each electric utility company[19] that sells electricity for consumption in Hawaii shall establish a renewable portfolio standard of:

(1) 10% of its net electricity sales by December 31, 2010;
(2) 15% of its net electricity sales by December 31, 2015; and
(3) 20% of its net electricity sales by December 31, 2020.

HRS §269-91 defines "renewable portfolio standard" to mean "the percentage of electrical energy sales that is represented by renewable electrical energy." HRS §269-92(b)(1) requires that at least fifty per cent of the renewable portfolio standards be met by electrical energy generated using renewable energy as the source.

The parties to the October 20, 2008 *Energy Agreement Among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and Hawaiian Electric Companies* ("Energy Agreement") agreed to seek modification of Hawaii's RPS goals to require that 40% of the HECO Companies' total RPS must be provided from renewable sources by 2030, and that through 2015 no more than 30% of the Companies' total RPS may come from imported biofuels consumed in utility-owned units.

The Legislature subsequently passed H.B. No. 1464, H.D. 3, S.D. 2, C.D. 1 ("HB 1464"), which will add to or amend various portions of HRS related to clean energy once it is signed or allowed to become law. The bill states that: "Attaining independence from Hawaii's detrimental reliance on fossil fuels has been a longstanding objective for the State." "Hawaii is the state

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provides, sells or transmits the portion of such power not used for such purposes directly to a public utility for transmission to the public." See HRS § 269-1(7) (emphasis added).

[19] HRS § 269-93 provides that: "An electric utility company and its electric utility affiliates may aggregate their renewable portfolios in order to achieve the renewable portfolio standard."

most dependent on petroleum for its energy needs. It pays the highest electricity prices in the United States, and its gasoline costs are among the highest in the country." As a result, "Reducing our oil dependence and the consequent price volatility and attaining energy security are critical."

HB 1464 increases the electric utilities' 2020 RPS requirement from 20% to 25%, and adds a new 40% requirement for the year 2030. Prior to January 1, 2015, at least 50% of a utility's RPS must be met by "electrical generation using renewable energy as the source". After January 1, 2015, however, a utility's entire RPS will need to be met by renewable generation, and "electrical energy savings" will no longer count toward RPS requirements.

Part VI of HB 1464 directs the Commission to establish "energy-efficiency portfolio standards that will maximize cost-effective energy-efficiency programs and technologies." In particular, HB 1464 requires that the energy-efficiency portfolio standards be designed to achieve 4,300 GWh of electricity use reductions statewide by 2030, with interim Commission-established goals for 2015, 2020, and 2025. The Commission "may also adjust the 2030 standard to maximize cost-effective energy-efficiency programs and technologies."

2. Revisions to Renewable Portfolio Standards

HRS § 269-95, as amended by Act 162 (2006), provides in relevant part that the Commission must:

> (3) Contract with the Hawaii natural energy institute of the University of Hawaii to conduct independent studies to be reviewed by a panel of experts, which must include findings and recommendations regarding:
>
> (A) The capability of Hawaii's electric utility companies to achieve renewable portfolio standards in a cost-effective manner; and
>
> (B) Projected renewable portfolio standards to be set five and ten years beyond the then current standards;

(4) Revise the standards based on the best information available at the time if the results of the studies conflict with the renewable portfolio standards established by Section 269-92; and

(5) Report its findings and revisions to the renewable portfolio standards to the Legislature no later than 20 days before the convening of the regular session of 2009, and every five years thereafter.

The parties to the Energy Agreement also agreed that the RPS goals should be reevaluated every five years beginning in 2013 to determine whether they remain achievable, taking into account changes in technology, the status of the projects contemplated in this agreement, and necessary regulatory support.

HB 1464 amends HRS §269-95 to provide that the Commission shall:

(1) By December 31, 2007, develop and implement a utility ratemaking structure, which may include performance-based ratemaking, to provide incentives that encourage Hawaii's electric utility companies to use cost-effective renewable energy resources found in Hawaii to meet the renewable portfolio standards established in section 269-92, while allowing for deviation from the standards in the event that the standards cannot be met in a cost-effective manner or as a result of events or circumstances, such as described in section 269-92(d), beyond the control of the utility that could not have been reasonably anticipated or ameliorated;

(2) Gather, review, and analyze empirical data to:

(A) Determine the extent to which any proposed utility ratemaking structure would impact electric utility companies' profit margins; and

(B) Ensure that the electric utility companies' opportunity to earn a fair rate of return is not diminished;

(3) Use funds from the public utilities special fund to contract with the Hawaii natural energy institute of the University of Hawaii to conduct independent studies to be reviewed by a panel of experts from entities such as the United States Department of Energy, National Renewable Energy Laboratory, Electric Power Research Institute, Hawaii electric utility companies, environmental groups, and other similar institutions with the required expertise. These studies shall include findings and recommendations regarding:

(A) The capability of Hawaii's electric utility companies to achieve renewable portfolio standards in a cost-effective manner and shall assess factors such as:

(i) The impact on consumer rates;

(ii) Utility system reliability and stability;

(iii) Costs and availability of appropriate renewable energy resources and technologies;

(iv) Permitting approvals;

(v) Effects on the economy;

(vi) Balance of trade, culture, community, environment, land, and water;

(vii) Climate change policies;

(viii) Demographics; and

(ix) Other factors deemed appropriate by the commission; and

(B) Projected renewable portfolio standards to be set five and ten years beyond the then current standards;

(4) Evaluate the renewable portfolio standards every five years, beginning in 2013, and may revise the standards based on the best information available at the time to determine if the standards established by section 269-92 remain effective and achievable; and

(5) Report its findings and revisions to the renewable portfolio standards, based on its own studies and other information to the legislature no later than twenty days before the convening of the regular session of 2014, and every five years thereafter.

3. Cost-Effective

Under HRS §269-95(1), the Commission is supposed to allow "for deviation from the standards in the event that the standards cannot be met in a cost-effective manner or as a result of events or circumstances, such as described in section 269-92(d), beyond the control of the utility that could not have been reasonably anticipated or ameliorated . . . ."

HRS § 269-91 defined "cost-effective" to mean "the ability to produce or purchase electric energy or firm capacity, or both, from renewable energy resources at or below avoided

costs consistent with the methodology set by the public utilities commission in accordance with section 269-27.2."

As noted above, Act 50 (2009) has amended the definition of "cost effective" in the RPS law (HRS § 269-91) by adding the underscored: "'Cost-effective' means the ability to produce or purchase electric energy or firm capacity, or both, from renewable energy resources at or below avoided costs or as the commission otherwise determines to be just and reasonable consistent with the methodology set by the public utilities commission in accordance with section 269-27.2."

4. Penalties

HRS § 269-92, as amended by Act 162 (2006), provides:

> (c) If the public utilities commission determines that an electric utility company failed to meet the renewable portfolio standard, after a hearing in accordance with chapter 91, the utility shall be subject to penalties to be established by the public utilities commission; provided that if the commission determines that the electric utility company is unable to meet the renewable portfolio standards due to reasons beyond the reasonable control of an electric utility, as set forth in subsection (d), the commission, in its discretion, may waive in whole or in part any otherwise applicable penalties.
>
> (d) Events or circumstances that are outside of an electric utility company's reasonable control may include, to the extent the event or circumstance could not be reasonably foreseen and ameliorated:
>
> (1) Weather-related damage;
>
> (2) Natural disasters;
>
> (3) Mechanical or resource failure;
>
> (4) Failure of renewable electrical energy producers to meet contractual obligations to the electric utility company;
>
> (5) Labor strikes or lockouts;
>
> (6) Actions of governmental authorities that adversely affect the generation, transmission, or distribution of renewable electrical energy under contract to an electric utility company;
>
> (7) Inability to acquire sufficient renewable electrical energy due to lapsing of tax credits related to renewable energy development;

(8) Inability to obtain permits or land use approvals for renewable electrical energy projects;

(9) Inability to acquire sufficient cost-effective renewable electrical energy;

(10) Substantial limitations, restrictions, or prohibitions on utility renewable electrical energy projects; and

(11) Other events and circumstances of a similar nature.

In 2006, the Commission initiated a proceeding pursuant to Act 162 (2006) in which it established an RPS penalty framework. See Order No. 23191, issued January 11, 2007, Decision and Order No. 23912, issued December 20, 2007 ("D&O 23912"), and Order Relating to RPS Penalties, issued December 19, 2008, in Docket No. 2007-0008.

5. Incentives

HRS § 269-94 provides that: "The public utilities commission may provide incentives to encourage electric utility companies to exceed their renewable portfolio standards or to meet their renewable portfolio standards ahead of time, or both."

HRS § 269-95, as amended by Act 162 (2006),[20] provides in relevant part that the Commission must:

(1) By December 31, 2007, develop and implement a utility ratemaking structure, which may include but is not limited to performance-based ratemaking, to provide incentives that encourage Hawaii's electric utility companies to use cost-effective renewable energy resources found in Hawaii to meet the renewable portfolio standards established in section 269-92, while allowing for deviation from the standards in the event that the standards cannot be met in a cost-effective manner, or as a result of circumstances beyond the control of the utility that could not have been reasonably anticipated or ameliorated;

(2) Gather, review, and analyze empirical data to determine the extent to which any proposed utility ratemaking structure would impact electric utility companies' profit margins, and to ensure that these profit margins do not decrease as a result of the implementation of the proposed ratemaking structure . . . .

[20] As noted above, HB 1464 amends HRS § 269-95 in certain respects.

By Order No. 23913, also filed December 20, 2007 ("Order 23913"), the Commission opened a new docket, Docket No. 2007-0416 (the "REIP Docket"), for the examination of the Companies' proposed Renewable Energy Infrastructure Program.

D. HRS § 269-6(b)

The 2007 Legislature passed Act 177, which explicitly states that the Commission may consider the need for increased renewable energy in rendering decisions on utility matters. Potentially, if energy from a renewable source were more expensive than energy from fossil fuel, the Commission may still approve the purchase of energy from the renewable source. In enacting Act 177, the Legislature found that: "Progressive energy policy-making at the state level is one of the most important issues on the current legislative agenda."

E. JUST AND REASONABLE

The "just and reasonable" standard is the general standard applicable to the setting of rates by regulatory commissions. See, e.g., HRS § 269-16(b). This same standard was imported as part of the standard applicable to the setting of prices to be paid to non-fossil fuel producers by the Commission under HRS § 269-27.2, and to QFs by regulatory commissions under PURPA. For example, PURPA requires that sales for purchases from QFs (1) "be just and reasonable to the electric consumers of the electric utility and in the public interest", (2) not discriminate against QFs, and (3) not exceed the incremental cost to the electric utilities of "alternative electric energy". FERC determined that the rates that should be paid (at least at the time it adopted its rules) should equal the utilities incremental costs, which it termed avoided costs.

Despite its long-standing and widespread use, the "just and reasonable" standard provides limited guidance in prescribing payment rates. In the rate making context, the Hawaii Supreme

Court has stated that "the reasonableness of rates is not determined by a fixed formula but is a fact question requiring the exercise of sound discretion by the Commission." In re Hawaii Electric Light Co., 60 Haw. 625, 636, 594 P.2d 612, 621 (1979), citing Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944), as well as decisions from other states. The Hawaii Supreme Court further stated that:

> As the United States Supreme Court concluded in the Hope case, supra, 320 U.S. at 602:
>
> > Under the statutory standard of "just and reasonable" it is the result reached and not the method employed which is controlling. . . . It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust or unreasonable, judicial inquiry . . . is at an end.

In re Hawaii Electric Light Co., 60 Haw. at 637, 594 P.2d at 621.

RESPONSES TO LEGAL QUESTIONS

The following section of these Responses responds to Sections VI through IX of the legal questions that were posed in this docket.[21]

VI. General

A. Does Section 269-27.2(b), HRS, empower the Commission to establish a set of feed-in tariffs that compel the utility to offer to purchase power from nonfossil fuel producers at rates, terms and conditions established by the Commission, even if those rates, terms and conditions differ from those proposed by the utility in this proceeding?

The Commission has general supervision over public utilities. A number of statutes set forth these general supervision powers. For example, as amended by Act 50 of the 2009 Session Laws of Hawaii, HRS § 269-27.2 addresses the utilization of electricity generated from nonfossil fuel sources, and provides (in relevant part) that:

> (a) The public utilities commission shall investigate and determine the extent to which electricity generated from nonfossil fuel sources is available to public

[21] For purposes of this section, the headings and subheadings are numbered according to the numbering on the questions distributed by the Commission on May 8, 2009.

utilities that supply electricity to the public, which electricity is in excess of that utilized or otherwise needed by the producers for their internal uses and which the producers are willing to make available to the electric public utilities.

(b) The public utilities commission may direct public utilities that supply electricity to the public to arrange for the acquisition of and to acquire electricity generated from nonfossil fuel sources as is available from and the producers are willing and able to make available to the public utilities, and to employ and dispatch the nonfossil fuel generated electricity in a manner consistent with the availability thereof to maximize the reduction in consumption of fossil fuels in the generation of electricity to be provided to the public. To assist the energy resources coordinator in effectuating the purposes of chapter 201N, the public utilities commission may develop reasonable guidelines and timetables for the creation and implementation of power purchase agreements.

(c) The rate payable by the public utility to the producer for the nonfossil fuel generated electricity supplied to the public utility shall be as agreed between the public utility and the supplier and as approved by the public utilities commission; provided that in the event the public utility and the supplier fail to reach an agreement for a rate, the rate shall be as prescribed by the public utilities commission according to the powers and procedures provided in this chapter.

The commission's determination of the just and reasonable rate shall be accomplished by establishing a methodology that removes or significantly reduces any linkage between the price of fossil fuels and the rate for nonfossil fuel generated electricity to potentially enable utility customers to share in the benefits of fuel cost savings resulting from the use of nonfossil fuel generated electricity. As the commission deems appropriate, the just and reasonable rate for nonfossil fuel generated electricity supplied to the public utility by the producer may include mechanisms for reasonable and appropriate incremental adjustments, such as adjustments linked to consumer price indices for inflation or other acceptable adjustment mechanisms. [22]

In addition, HRS § 269-6(a) vests the Commission with "the general supervision . . . over all public utilities. . . ." HRS § 269-6(b) provides that "[t]he public utilities commission may consider the need for increased renewable energy use in exercising its authority and duties . . . ." Moreover, HRS § 269-7 provides, "The public utilities commission and each commissioner shall have power to examine into the condition of each public utility, . . . and all matters of every nature affecting the relations and transactions between it and the public or persons or corporations." Further, HRS § 269-16 states, "All rates, fares, charges, classifications,

[22] Emphasis added.

schedules, rules, and practices made, charged, or observed by any public utility or by two or more public utilities jointly shall be just and reasonable and shall be filed with the public utilities commission."

Based on these statutory provisions, the Commission has the authority to require the utility offer to purchase power from nonfossil fuel producers at rates, terms and conditions established by the Commission, even if those rates, terms and conditions differ from those proposed by the utility in this proceeding.

In exercising its powers, however, the Commission is required to act in accordance with the statutory provisions pursuant to which it derives its authority, and the Commission may be constrained in some areas by PURPA. As indicated in the "Background" section above, guidance is provided not only in HRS § 269-27.2(c) (which addresses the rate payable by the public utility to the producer), but is also provided in the RPS law.

B. Does the Commission have authority to mandate that the utility procure a particular quantity of nonfossil electricity, exceeding the statutory RPS requirements? Can the Commission establish deadlines? What statutes grant this authority?

State energy policy strongly encourages the use of renewable energy resources, but it also includes other objectives, such as dependable, efficient, and economical statewide energy systems.

The RPS law provides minimum objectives, and allows for the imposition of penalties (subject to a number of considerations) if the standards are not achieved. It also identifies factors that must be considered in meeting even the minimum standards.

Thus, the Commission does not have the authority (except as provided by the RPS law itself) to establish higher standards, backed by penalties. But the Commission does have the authority to implement programs that may result in achievement of higher levels of renewable

energy penetration, as long as it acts in accordance with the statutory provisions from which it derives its authority.

HRS § 269-94 provides that: "The public utilities commission may provide incentives to encourage electric utility companies to exceed their renewable portfolio standards or to meet their renewable portfolio standards ahead of time, or both."

As amended by HB 1464 (2009), HRS § 269-95(4) provides that the Commission shall: "Evaluate the renewable portfolio standards every five years, beginning in 2013, and may revise the standards based on the best information available at the time to determine if the standards established by section 269-92 remain effective and achievable[.]" (Emphasis added.) This provision could be read as granting the Commission the authority to increase the current RPS (and/or establish RPS-related deadlines) to the extent that such revision would aid in the "effectiveness" of the statute. However, it appears that any such increase would also need to be "achievable".

C. Is the Energy Agreement binding on any one? In what way? Who could sue whom for noncompliance?

The Energy Agreement is a document containing both binding and non-binding provisions directed toward moving Hawaii "more decisively and irreversibly away from imported fossil fuel for electricity and transportation and towards indigenously produced renewable energy and an ethic of energy efficiency."[23]

Some of the items in the Energy Agreement form commitments among the parties to the Energy Agreement with obligations by the parties. For example, with respect to HECO's commitment –

> to integrate, with the assistance of the State to accelerate the commitment, up to 400 MW of wind power into the Oahu electrical system that is produced by one or

[23] Energy Agreement at 1.

more wind farms located on either the island of Lanai or Molokai and transmitted to Oahu via undersea cable systems[24]

– the Energy Agreement requires that "[t]he State shall first seek, with Hawaiian Electric's and/or developer(s) reasonable assistance, federal grant or loan assistance to pay for the undersea cable systems".[25] As a second example, the Energy Agreement provides that "[d]istributed generation interconnection will be limited on a per-circuit basis, where generation (including PV, micro wind, internal combustion engines, and net metered generation) feeding into the circuit shall be limited to no more than 15% of peak circuit demand for all distribution-level circuits of 12kV or lower[.]"[26]

However, the Energy Agreement also recognizes that accomplishing some of the initiatives requires the action of other entities that are not parties to the agreement. For example, the Energy Agreement recognizes that some initiatives require Commission approval before thy can be implemented. The agreement calls for the HECO Companies to "facilitate the development of photovoltaic (PV) energy by submitting an application to the PUC for a 'PV Host Program'" which, if approved by the Commission, would provide that the cost of acquiring photovoltaic ("PV") energy under the program "shall be paid for by all ratepayers."[27] To provide another example, the Energy Agreement states that the HECO Companies "will encourage and explore the development of" a number of project proposals to be filed with the Commission, including an "Airport DG (8 MW) Biofuel" project.[28]

In addition, some initiatives in the Energy Agreement involve the submission of clean energy measures to the State Legislature. For example, with respect to increasing the goals set

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[24] Id. at 4.
[25] Id. at 5.
[26] Id. at 28.
[27] See id. at 12-13.
[28] See id. at 7-8.

forth in the RPS law, the agreement provides that the HECO Companies "will support the State and/or the PUC in incorporating these changes in the HRS §269-92, or in the exercise of the PUC authority."[29] To that end, the 2009 Legislature passed HB 1464 in order "to provide a first step in aligning Hawaii's energy policy laws with the State's energy goals."[30]

The Energy Agreement also contains other non-binding items including provisions that: (1) simply describe current conditions, e.g., "The islands of Hawaii have abundant natural resources, including wind, sunshine, ocean and geothermal sources for electricity generation, and land for energy crops that can be refined into biofuels to address electricity and transportation needs";[31] and (2) reflect preliminary agreements in principle, e.g., "The parties agree in principle that a 'smart grid' is a critical component of Hawaii's energy future".[32]

D. Does the Commission have authority to adopt FiTs in this proceeding without having completed a proceeding on Clean Energy Scenario Planning?

The Commission has the authority to adopt a FIT in this proceeding without having completed a proceeding on Clean Energy Scenario Planning ("CESP"). In fact, the Joint Proposal on Feed-In Tariffs of the HECO Companies and Consumer Advocate ("Joint Proposal"), filed December 23, 2008, contemplated that a FIT would be adopted prior to the completion of the initial CESP proceeding.[33]

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[29] Id. at 18.

[30] Among other things, HB1464: (1) increases electric utilities' 2020 RPS requirement from 20% to 25%, and adds a new 40% requirement for the year 2030; and (2) directs the Commission to establish "energy-efficiency portfolio standards that will maximize cost-effective energy-efficiency programs and technologies."

[31] Id. at 1.

[32] Id. at 31.

[33] For example, pages 13-14 of KEMA's HECO Feed-In Tariff Program Plan, attached to the Joint Proposal, noted that an "accelerated two year interval for conducting the first FIT review and update was deemed desirable and reasonable" because, among other things, "[t]he initial locational value maps of the Clean Energy Scenario Planning ('CESP') process are expected to be completed within the next two years."

Deferring implementation of a FIT until completion of a CESP proceeding would lengthen the time for the adoption of a FIT. The development of a CESP framework and CESP plans (to replace the Companies' IRP framework and plans)[34] would take some amount of time. For example, it took over five years to go from the opening of the initial IRP docket to establish a framework to the approval of HECO's first IRP plan.[35]

E. Under a FiT regime, will there still be a need for a contract between seller and the utility buyer? What form would these written contracts take? What seller obligations should these contracts cover?

Under a FIT regime there will still be a need for a contract between the seller and utility. As explained in the Joint Proposal, a FIT is generally defined as an offering of a fixed-price contract over a specified term with specified operating conditions to eligible renewable energy generators, and is best suited for renewable energy contracts that lend themselves to the use of standardized rates, terms and conditions. See Joint Proposal at 3.

The Final Statement of Position of the HECO Companies and the Consumer Advocate ("Joint FSOP"), filed March 30, 2009 proposed that the FIT would include a standard form of contract to cover the sale of energy. See Joint FSOP at 4.[36] The substantive provisions contained in the FIT standard contracts would set forth the terms and conditions under which the

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[34] Section 32 of the Energy Agreement provides that "[t]o improve analysis and guidance for Hawaii's clean energy future, the parties agree to replace the current Integrated Resource Planning (IRP) process with a new Clean Energy Scenario Planning (CESP) process."

[35] Order No. 10458 in Docket No. 6617 was issued on January 10, 1990, thereby initiating the Commission's proceeding to implement an IRP process. The IRP Framework was established approximately 26 months later on March 12, 1992, when the Commission issued Decision and Order No. 11523. By Decision and Order No. 11630, filed May 22, 1992, the IRP Framework was revised. HECO's initial IRP Plan ("HECO IRP-1") docket (Docket No. 7257) was opened on March 13, 1992. Decision and Order No. 13839, issued on March 31, 1995 approved the HECO IRP-1. The HECO Companies and the other parties to the IRP process have gained experience in resource and scenario planning as a result of the prior IRP dockets. As a result, the time to complete the initial CESP docket and initial HECO Companies' CESP proceedings could be shorter than the five-year period.

[36] The HECO Companies have other tariffs that include standard forms of contract. For example, the HECO Companies' Rule 18 (concerning Net Energy Metering) included as part of that tariff filing a standard form of contract that covered the terms and conditions under which the net energy metering arrangement would occur.

sale of energy would occur as well as the rights and obligations of the seller and the utility. For example, the contract provisions would include terms and conditions such as pricing for the purchase of energy, billing and payment, contract term, interconnection and metering.

F. Assuming there are contracts associated with FiT sales, what is the Commission's statutory obligation to review these contracts? What are effective procedures to expedite Commission review?

Commission review of the FIT contracts can be streamlined through the use of a standard form of contract. The standard form of contract can be part of the FIT tariff. This way, the Commission will have the opportunity to review the rates for energy to be offered to sellers as well as the other terms and conditions to be included in the contracts.

Once the FIT is approved, the Companies would be able to flow the cost of energy purchased under the FIT through the Energy Cost Adjustment Clause ("ECAC"), without obtaining separate Commission approval. In this regard, the relevant portion HAR § 6-60-6 states:

> Automatic adjustment clauses. The utility's rate schedules may include automatic rate adjustment clauses, only for those clauses previously approved by the commission. Upon effective date of this Chapter, any fuel adjustment clause submitted for commission approval shall comply with the following standards:
> * * *
> (2) No changes in fuel and purchased energy costs may be included in the fuel adjustment clause unless the contracts or prices for the purchase of such fuel or energy have been previously approved or filed with the commission.[37]

Accordingly, in the event that the Commission approves prices to be paid to sellers under a FIT, the cost of that energy could be passed through the ECAC without the Commission's approval of the specific contract covering the customer-generator providing that energy. If, however, it is determined that Commission approval of each FIT contract entered into by the

[37] Emphasis added.

HECO Companies is required in order to flow the payments made to the sellers through the ECAC, then the HECO Companies will submit each contract for Commission approval.

To streamline the process, the decision and order implementing a FIT and the standard form of contract to be used for the FIT can state that: (1) the contract shall be effective upon execution by both parties; (2) the HECO Companies shall file, for notification purposes only, the executed FIT contracts; and (3) the HECO Companies may recover the energy payments made under the contract through the ECAC.

VII. Cost

A. Does HRS 269-27.2 impose any limit on total cost? For example:

1. Does the phrase "maximize the reduction in fossil fuels" in Section 269-27.2(b) allow the Commission to establish a quantity goal, determine the rate necessary to satisfy the goal, and impose that rate regardless of how high the rate is and regardless of total cost?

No. The rate and total cost must be considered by the Commission, along with other factors identified in the relevant statutory provisions. See response to Question VI.B. In other words, the phrase "maximize the reduction in fossil fuels" cannot be read or applied in isolation, or without considering the overall statutory context.

2. Does the "maximize" phrase mandate that result?

No. See response to Question VII.A.1.

3. If you believe the "maximize" phrase mandates that result, what effect does the discretionary term "may" have on the Commission's obligation?

Not applicable.

4. Can the Commission determine a required quantity for the utility to purchase, and then set the rate at whatever level is necessary to attract that quantity? Would such a rate necessarily satisfy the just and reasonable standard?

Under the "set aside" concept, the Commission can determine the quantity that should be acquired, and set a price targeted to obtaining that quantity. However, the rate must satisfy the "just and reasonable" requirement, as well as other factors identified in the relevant statutory provisions. This can be done in two ways – by establishing the target, but limiting the rate (which was the approach taken in the RPS law), or by establishing the set aside amount taking into consideration the rate that will be needed to achieve that target (as well as other factors relevant to whether a target amount should be established).

B. Regardless of any statutory limit on cost, does the Commission have authority to establish a dollar limit on the cost of utility acquisition of nonfossil electricity pursuant to an FIT? What statutes grant this authority?

Inherent in the Commission's authority to establish (or prevent the establishment of) a FIT is the authority to limit or constrain the availability of the FIT (including the authority to establish a dollar limit).[38]

C. Does this authority to establish a dollar limit apply only to acquisition above the quantities required by the RPS statute?

No. See response to VII.B.

[38] If the FIT were established by statute, then the constraints would be limited to those allowed by or consistent with the statutory mandate. This is the case with Net Energy Metering.

VIII. Seller's Legal Rights

A. PURPA

1. Does a nonfossil developer have an existing statutory right, under state law or PURPA, to a negotiated PPA? If so, does that right continue even if the Commission establishes FiTs that constitute utility offers to buy at a stated rate, or can the Commission make the FiT the exclusive means by which nonfossil producers sell to the utility? Put another way, if there is a FiT applicable to a particular seller, may the Commission authorize (or forbid) the utility to negotiate a PPA on terms that vary from the FiT?

No. The terms of the PPA can be fixed, as they are with Schedule Q contracts. See also the discussion in the "Background" section and in the response to VIII.B. concerning the rights of non-fossil fuel producers' rights to sell energy to a utility. As discussed in the response to VIII.B., HRS § 269-27.2 is not written to be the "PURPA equivalent" for non-fossil fuel producers. Unlike PURPA, it does not convey rights directly to non-fossil fuel producers. Instead, it permits the Commission to direct electric utilities to acquire energy made available by non-fossil fuel producers. The Commission's QF rules have not been amended to directly apply to non-fossil fuel producers that are not QFs. However, a non-fossil fuel producer may be able to meet the QF eligibility standards and self-certify as a QF. In that situation, the non-fossil fuel producer may also have rights under PURPA.

2. Can the Commission substitute a FiT for Schedule Q, as a means of complying with PURPA? What type of issuance from the Commission would be necessary to demonstrate PURPA compliance?

Depending on the scope of the FIT that is implemented, the Commission could substitute a FIT for Schedule Q as a means of complying with PURPA.

The Commission's rules relating to QFs and PPAs between QFs and electric utilities are codified in its Standards for Small Power Production and Cogeneration, and are included in Title

6, Chapter 74, HAR. The rules were adopted in 1982 (and amended from time to time thereafter) pursuant to rules adopted by FERC pursuant to PURPA.

Schedule Q is the HECO Companies' mechanism for complying with HAR § 6-74-22(b), which provides that:

> (b) There shall be placed into effect with respect to each electric utility, standard rates for purchases from qualifying facilities with a design capacity of one hundred kilowatts or less. The standard rates for purchases under this subsection:
>
> (1) Shall be consistent with subsection (a) and § 6-74-23; and
>
> (2) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.[39]

HAR § 6-74-22(b) does not provide for any limits on the amount of purchases from QFs (either in the form of kWh purchased or amount of total installed MWs that are eligible to receive the rate pursuant to HAR § 6-74-22(b)). As a result, in order to substitute for Schedule Q, if a FIT includes targets as to the amount of generation that is eligible to participate, the situation as to what happens to other eligible QFs where the FIT targets are achieved should be addressed. In general, however, the FIT limits are designed to address factors such as reliability issues, which are appropriate considerations in addressing the rights of QFs to interconnect with utility systems.

In addition, under HAR § 6-74-22(b), eligible technologies include "biomass, waste, renewable resources, solar, wind, geothermal, or any combination thereof." As a result, in order to be a substitute for Schedule Q, a FIT would have to include at least these types of technologies as being eligible to participate under the FIT.

[39] Emphasis added.

B. Does HRS § 269-27.2 create any legal rights in sellers of nonfossil power? For example:

HRS Section 269-27.2 is not written to be the "PURPA equivalent" for non-fossil fuel producers. Unlike PURPA, it does not convey rights directly to non-fossil fuel producers. Instead, it permits the Commission to direct electric utilities to acquire energy made available by non-fossil fuel producers. The Commission's QF rules have not been amended to directly apply to non-fossil fuel producers that are not QFs. On the other hand, the HECO Companies generally have negotiated with non-fossil fuel producers that are not QFs in the same manner as they have negotiated with QFs. (In addition, most [but not necessarily all] non-fossil fuel producers can meet the QF eligibility standards, and self-certify as QFs.)

1. Does the phrase "just and reasonable rate" in HRS § 269-27.2(c) mean "just and reasonable" to the seller, or only "just and reasonable" to the consumer? That is, does the phrase "just and reasonable rate" allow a seller to contest a Commission-established FiT on the grounds that the rate is too low or that non-rate terms and conditions are unfavorable?

The ability of "sellers" to contest the rates, or terms and conditions, in a FIT, generally would depend on whether they have rights (for example, as QFs) that would be constrained as a result of the FIT (for example, if the FIT was the only way they could sell power to the utility). Even QFs would have limited ability to contest the outcome if they could not show that the purchase rates were lower than avoided costs. Cost-based rates would probably pass the test, given the convergence of avoided costs and the costs of owning, operating and maintaining renewable generation. Also, as noted in the "Background" section above, PURPA generally does not dictate the terms and conditions of power purchase contracts.

2. **On what specific grounds could the seller contest the rate? That the rate produces a return on equity too low to attract sellers? How would the seller prove this case, to the Commission and to reviewing courts? What data would the Commission have to rely on to insulate its rate decision from judicial reversal? What evidentiary burden does the seller have, to supply facts to the Commission so that the Commission has the necessary factual support for its decision?**

Participants in this docket generally would have to meet the appellate standards in HRS Section 91-14 to appeal from the outcome of this proceeding.

3. **If the Commission declined to establish any FiT rates, but instead authorized the utility to self-produce or purchase renewables as the utility deems appropriate, would the sellers have any legal claim against the utility or the Commission? If the answer is no, then do the sellers have any legal right to contest a Commission-established FiT?**

See response to Questions VIII.B.1 and VIII.B.2.

C. **Assuming the Commission establishes FITs, may the Commission authorize (or forbid) sellers with existing PPAs to terminate the PPA and enter into an agreement under the FIT? Under what conditions? With what Commission involvement?**

PPAs between an electric utility and a seller form a contractual relationship between the parties. (Generally, Commission approval is obtained for these PPAs.) The PPAs include the rights and obligations of the parties, including the right to terminate the PPAs. As discussed in the response to question VI.A above, the Legislature has vested the Commission with the general supervision over all public utilities,[40] including electric utilities. In general, although the

[40] As defined in HRS § 269-1, the term "Public Utility" generally includes:
every person who may own, control, operate, or manage as owner, lessee, trustee, receiver, or otherwise, whether under a franchise, charter, license, articles of association, or otherwise, any plant or equipment, or any part thereof, directly or indirectly for public use, for the transportation of passengers or freight, or the conveyance or transmission of telecommunications messages, or the furnishing of facilities for the transmission of intelligence by electricity by land or water or air within the State, or between points within the State, or for the production, conveyance, transmission, delivery, or furnishing of light, power, heat, cold, water, gas, or oil, or for the storage or warehousing of goods, or the disposal of sewage; provided that the term shall include:
(A) Any person insofar as that person owns or operates a private sewer company or sewer facility; and

Commission has broad powers with respect to the regulation of public utilities, the Commission does not have the right to abrogate or terminate existing contracts (unless the right was reserved to the Commission in the contract). As a result, it does not appear that the Commission would have the power to authorize (or forbid) a seller with an existing PPA to terminate a PPA (or from entering into a PPA under the FIT).

For purposes of the period when the initial FIT is effective up through the first FIT update, the HECO Companies have stated that they are willing to allow sellers with existing Schedule Q contracts to migrate to FIT contracts. The immediate decision to switch from a Schedule Q contract to a FIT contract would be left to the seller. The seller can then determine which contract the seller prefers as there may be differences in the terms and conditions of the contracts. It should be noted, however, that Schedule Q contracts can be terminated after one year, and the form of pricing in the FIT contracts will be consistent with HRS § 269-27.2. The intent of the utilities in the Schedule Q proceeding, Docket No. 2008-0069, was to modify the form of pricing used in the Schedule Q contracts.

D. Hawaii statutes prohibit undue discrimination in the provision of utility service. How does that prohibition apply in the context of FiTs? For example:

1. Can there be different rates for different technologies/sizes/islands: What factual differences are necessary to justify rate differences?

Under the Joint Proposal of the HECO Companies and the Consumer Advocate, the FIT rates will be based on cost data collected from similar installations in Hawaii and include a reasonable profit amount to be approved by the Commission. Setting FIT rates for eligible technologies requires assessing a price at which the target generator will be viable, covering all of its actual costs and providing a sufficient rate of return to investors to attract investment.

(B) Any telecommunications carrier or telecommunications common carrier[.]

Consistent with the Commission's Scoping Paper, a model utilizing a discounted cash flow ("DCF") analysis methodology would be used to assess the nominal levelized FIT rates based on the cost of generation plus a target return on investment ("ROI"), or Internal Rate of Return ("IRR"), for the project over the life of the system. The base rate would represent, for a project coming on line in a given year, a nominal levelized payment stream that has the same net present value ("NPV") as the projected stream of costs and capital flows that provides the target IRR to project owners.

As the cost to install units could differ, based on facts such as the type of technology being installed, the location of the unit (which could take into account the typical interconnection costs), and the size of the installation, the Commission's rules contemplate that there could be different payment rates due to different types of technologies used by sellers. For example, the Commission's Standards for Small Power Production and Cogeneration (HAR, Title 6, Chapter 74) provides that rates for purchases from QFs may differentiate among QFs using various technologies on the basis of the supply characteristics of the different technologies. HAR § 6-74-22(b)(2).

In addition, it should be kept in mind that utility customers on different islands are charged different rates (e.g., cents/kWh) for electricity. Even on the same island, often times different categories of customers (residential versus commercial and industrial) are charged different rates for electricity.

In order to support differences in the rates payable under a FIT, the rates should be supported by reliable, probative and substantial evidence. An agency's findings, if supported by reliable, probative and substantial evidence, will be upheld. In re Gray Line Hawai'i, Ltd., 93 Haw. 45, 53 (2000). In Hawaii, "Substantial evidence means credible evidence of sufficient

quantity and probative value to justify a reasonable man in reaching a conclusion." Hong v. Kong, 5 Haw. App. 174, 174, 683 P.2d 833, 835 (1984).

More specifically:

> The substantial evidence standard of review applied to agency's factual findings does not require or specify a quantity of evidence but requires only such relevant evidence as a reasonable mind might accept as adequate to support a conclusion. It has been said that substantial evidence is something less than the weight of the evidence. So, also, substantial evidence is somewhat less than and does not mean, nor is it equated with, a preponderance of evidence. . . . In any event, substantial evidence is more than a mere scintilla, and, in order to be substantial, the evidence must do more than create a suspicion of the existence of the fact to be established.

73A C.J.S. Public Administrative Law and Procedure § 448 (2004).

With respect to the rates to be paid sellers under a FIT, substantial evidence could include any credible evidence of sufficient quantity and probative value to justify a reasonable person in concluding that the FIT rates are reflective of known cost data (plus a reasonable profit to be determined by the Commission) for comparable renewable projects in Hawaii. Examples of such evidence could include actual costs of projects of similar size, in similar locations, utilizing comparable technologies, and/or featuring typical interconnection requirements.

While it would be preferable to have Hawaii-specific data regarding the costs and technical requirements of all future projects prior to establishing FIT tariff rates for those projects, the HECO Companies recognize that such data may not yet be available when the time comes to establish FIT tariff rates for some of those projects. Thus, in certain instances, it may be necessary to establish those FIT tariffs based in part on non-Hawaii cost evidence.

Substantial evidence in this regard could include any credible evidence of sufficient quantity and probative value to justify a reasonable person in concluding that the FIT rates are reflective of what the cost (plus a reasonable profit) for a typical and comparable project in Hawaii would be. Examples of such evidence could include actual costs of non-Hawaii projects

of similar size, utilizing comparable technologies, and/or featuring comparable interconnection requirements, which data could then adjusted to reflect any difference in cost resulting from the project being sited at a specific location in Hawaii, as opposed to outside of Hawaii.

2. Can there be negotiated PPAs that make use of FiT rates but that vary from each other in other terms and conditions?

This question appears to be asking about a scenario where (1) a FIT is adopted, but only FIT rates are established in the FIT; and (2) the other terms and conditions under which sellers provide energy to utilities would not be established. Such a scenario is not an efficient process for sellers eligible under a FIT to provide energy to utilities. For instance, the Commission would have to review and approve each contract that is entered into by a utility and a seller under a FIT. This would lengthen the time for a utility to be able to start receiving energy from a seller. In addition, this scenario could create issues, as terms and conditions under which energy is provided could impact the allocation of risk and value received under a contract. In other words, the same rate may not be applicable to the same type of technology if there are substantially different terms and conditions in a contract. However, there could be contracts that negotiate some specific terms and conditions (e.g., interconnection requirements).

3. Can there be a negotiated PPA for projects that qualify under the scope of an existing FIT?

The HECO Companies and the Consumer Advocate propose that if a project qualifies under the scope of an existing FIT, then the seller should sell its energy to the HECO Companies through the FIT, which would include a standard form of contract. From an administrative standpoint, this would make the contracting process more efficient. For example, the Commission's review of the contract could be streamlined as the standard form of contract and rates would have already been reviewed and approved by the Commission. (See the response to Question VI.F.)

As previously discussed in the "Background" section above, as a practical matter, a utility's "PURPA" obligation is to offer to purchase at avoided costs under reasonable terms and conditions. At the same time, neither PURPA nor the Commission's PURPA rules specify all the terms and conditions that must be offered to QFs. If a utility offers more favorable terms through another process, such as a FIT, then QFs will need to comply with the FIT provisions in order to receive those more favorable terms, because neither PURPA nor the Commission's rules require that a utility offer those terms.

With the exception of price, interconnection and curtailment, the rules do not specify the terms and conditions upon which the purchase of capacity and/or energy must be made by the electric utility. For example, a utility is not required by PURPA to offer (1) a specific contract term, (2) a minimum take contract, (3) payments on any other basis than energy delivered, or (4) curtailment priority over existing energy producers.

IX. Utility Role

A. Does the Commission have the power to restrict the utility's ability to build its own nonfossil generation, such as requiring the utility to refrain from building whenever there is a viable independent seller offering to sell? What findings must the Commission make to support such a restriction?

B. Same question as above, but applied to a utility affiliate selling renewable energy to another utility affiliate.

The Commission's authority to permit, prohibit, or condition a utility affiliate's ownership of renewable generation would be limited by federal law (e.g., PURPA). For example, the Commission could not deny a right to an entity that is granted by PURPA. With the changes in the ownership criteria of QFs, it could be possible for an electric utility to own a QF. As a result, there could be a situation where a utility affiliate that is a QF could have a right under PURPA to sell energy to a utility. (See the discussion in the "Background" section above concerning the elimination of the ownership limitations for QFs previously in existence).

In addition, a prohibition on utility ownership of renewable generation also would be inconsistent with the RPS law. The RPS law sets forth renewable portfolio standards, and allows for the imposition of penalties (subject to a number of considerations) if the standards are not achieved. Unreasonable restrictions should not be established that prevent a utility from pursuing an opportunity to add additional renewable generation.

A prohibition on utility ownership of renewable generation would be inconsistent with a utility's obligation to serve. This was addressed in the Competitive Bidding docket (Docket No. 03-0372).

Based on the experience of mainland jurisdictions that implemented retail competition, and the uniqueness of the small, non-interconnected Hawaii markets, the Commission declined to implement retail competition in Hawaii. The Commission issued final Decision and Order No. 20584 ("D&O 20584") on October 21, 2003 in Docket No. 96-0493, which closed the competition docket instituted in 1996. The Commission determined that no action would be taken in the docket to implement retail electric competition or to substantially change the regulatory framework for the electric industry in Hawaii at this time. The Commission found that:

> Electric industry restructuring should only be initiated if it is in the public interest. Developments in other states indicate that, at best, implementation of retail access would be premature. In addition, projections of any potential benefits of restructuring Hawaii's electric industry are too speculative and it has not been sufficiently demonstrated that all consumers in Hawaii would continue to receive adequate, safe, reliable, and efficient energy services at fair and reasonable prices under a restructured market, at this time. Accordingly, the commission does not find it is in the public interest to completely restructure the electric industry at this time. We will continue, however, to keep a watchful eye on restructuring experiences in other states. In the alternative, the commission finds that it is in the public interest to work within the current regulatory scheme to strive to improve efficiency within the electric industry. (D&O 20584 at 14.)

The Commission also noted that:

> Hawaii is different from other states because, without interconnection to other states' energy transmission grid, Hawaii does not need to respond to the actions of its neighbors, and Hawaii does not have the advantages and disadvantages associated with being connected with other states. (D&O 20584 at 14 n.9.)

The Commission determined that it was in the public interest to work within the current regulatory system to strive to improve efficiency within the electric industry, and opened investigative dockets on competitive bidding and distributed generation to move toward a more competitive electric industry environment under cost-based regulation.

The isolated nature of the island's electrical system places a premium on reliability of power supply and increases the risk of project default and/or the failure of the independent generator to deliver the power. Unlike the mainland, the HECO Companies cannot resort to purchases of energy from the market during periods of generation shortfall if the project does not deliver the power as required under the contract.

IPPs do not have the same "obligation to serve" that the utility does, and their performance is not subject to regulatory review. IPPs generally will make decisions on whether or not to provide capacity or energy based on economics, and not on the potential impact of their decisions on the utility's customers. When customers experience a service interruption that is based on a shortfall of generation, the customers look to the utility, not the IPP, as the cause.

More stringent contract provisions such as higher security levels, clearly defined milestone schedules and associated damages if milestones are not adhered to, and other financial disincentives have been applied as solutions to mitigate this problem in other jurisdictions. On the mainland, access to security allows the utility to replace the contracted power through market purchases and the application of liquidated damages to make the utility's customers whole.

However, in Hawaii, even with stringent contract provisions and penalties for failure to perform under the contract, there is still the potential for an IPP to default on its obligation and incur the penalties. If the IPP cancels the project, the costs to customers could be much greater than the contract penalties alone if system reliability is jeopardized. At the end of the day, customers need electricity and contractual penalties paid by an IPP to the utility cannot replicate that.

Utilities have the obligation to serve their customers while IPPs who supply capacity and energy to the utilities under PPAs may be obligated to provide to the utility only those items and services, or to perform only those duties, that are covered by provisions in the PPA. At times, this can constrain the utility's operating flexibility. As a result, a utility has much more flexibility to adjust to changed circumstances if it owns and operates its own units, than if it purchases power under long-term PPAs, because PPAs cannot be drafted to provide for all future contingencies and changed circumstances.

Moreover, a prohibition on utility ownership of renewable generation would be inconsistent with the Competitive Bidding Framework.[41] For example, Part VI of the

[41] The Framework for Competitive Bidding, adopted by the Commission in Decision and Order No. 23121 ("D&O No. 23121"), issued December 8, 2006 in Docket No. 03-0372 is referred to as the "Competitive Bidding Framework".

Competitive Bidding Framework requires the utility to participate in certain competitive solicitations and to conduct parallel planning in the event purchased power facilities do not materialize.

DATED: Honolulu, Hawaii, June 12, 2009.

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I hereby certify that I have this day served the foregoing JOINT RESPONSES TO LEGAL QUESTIONS REGARDING FEED-IN TARIFFS OF THE HECO COMPANIES AND CONSUMER ADVOCATE via hand delivery or by U.S. Mail, postage prepaid, and properly addressed, as indicated below:

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